LOWERING THE EFFECTIVE COST OF CAPITAL FOR GENERATION PROJECTS

CALIFORNIA CREDIT POLICIES REPORT

SUMMARY OF JUNE 27, 2006 WORKSHOP

CONSULTANT REPORT

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January 2007
CEC-100-2007-001

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Abstract

The California Energy Commission held a public workshop titled “Lowering the Effective Cost of Capital for Generation Projects” on June 27, 2006. This report summarizes information and comments presented at the workshop and in subsequent written comments. It also makes three recommendations that address structural market issues, designed to provide the State of California with transformational policy options. Four additional recommendations cover incremental changes that do not appreciably change the existing market structure.

As articulated in this report, the workshop examined credit policies imposed on new generation projects in California, with particular emphasis on renewable generation. Workshop participants included investment bankers, power plant investors, portfolio managers, insurance companies, risk managers, developers, and investor-owned and municipal utilities. This report reflects the workshop participant’s comments, recommendations, questions, and exchanges on:

- Credit policies in California and other representative states.
- How California’s current credit policies contribute to project costs.
- The extent that these policies impede generation project development, including renewable projects.
- Prudent solutions that would satisfy present credit policies while lowering the effective cost of capital, including step-in rights, insurance products, risk pooling, and reducing credit requirements.
- Topics for future research and next steps.

List of Acronyms

CalPERS	California Public Employees’ Retirement System
CPUC	California Public Utilities Commission
DSCR	Debt coverage service ratio
EAP II	California Energy Action Plan II
EOB	Electricity Oversight Board
EPAct	Federal Energy Policy Act of 2005
EPC	Engineering/procurement/construction
ERC	Emission reduction credit
IEPR	Integrated Energy Policy Report
IOU	Investor-owned utility
IPP	Independent power producer
IRR	Internal rate of return
ISO	Independent System Operator
kW or kWh	Kilowatt or kilowatt-hour
LP or LLP	limited partnership or limited liability partnership
LSE	Load serving entity
LTPP	Long Term Procurement Plan
MPR	California market price referent
MW or MWh	Megawatt or megawatt-hour
NECC	North American Energy Credit and Clearing Corp
NPV	Net present value
PG&E	Pacific Gas and Electric
PPA	Power purchase agreement
PTC	Production tax credit
QF	Qualifying facility
RA	Resource Adequacy
REC	Renewable energy credit
RFO	Request for offers
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SEC	U.S. Securities and Exchange Commission
SPE	Special-purpose entity

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Executive Summary

“There’s a difference between liability, and having *all* of your risks completely collateralized.” --Constellation Energy

This quote from the California Energy Commission’s June 27, 2006 “Lowering the Effective Cost of Capital” workshop reflects what many power plant developers feel about existing California credit policies. Credit requirements established by California power purchasers reflect their experiences during the 1990s era of merchant plant developers and highly liquid national trading entities and the energy crisis of 2001. In a continuously evolving market, the application of credit policies developed for an earlier market form may adversely affect the development of power plants, especially renewable generators. Credit requirements imposed by power purchasers to ensure development and performance security may inadvertently restrict competition, and raise the price of power.

Efforts by the utilities to protect themselves from contract failure are not standardized. Although standardization may provide a more predictable investment climate, developers and the financial community suggested that modified credit requirements that recognize the risk-mitigation value of the project finance process itself or restructured insurance against contract failure might make more projects viable.

The Energy Commission held the June 27, 2006 workshop with these circumstances in mind. Suggestions made during the workshop for mitigating the effects of existing credit requirements included:

a. Recognizing the risk-mitigation value of step-in rights,
b. Emphasizing subordinated security and fractional ownership arrangements, and
c. Obtaining from the California Public Utilities Commission (CPUC) clarification regarding the exculpatory effects of project failure in assessing penalties for non-compliance with Renewables Portfolio Standard goals.

Insurance and securitization strategies were also suggested as a way of pooling the risk of many projects and creating opportunities for a wider range of investors to finance the collateral. A method for developing these strategies is included in the recommendations of this report. Encouraging participation of investor-owned utilities in insurance or securitization strategies could require changes in the power procurement process regulated by the CPUC.

Removing biases against small projects and projects that generate intermittently was a common concern that could be addressed by eliminating collateral thresholds that favor large projects, mark-to-market credit requirements, and collateral requirements based on nameplate capacity.

Chapter 7 of this report presents three recommendations addressing structural market issues, designed to provide the State of California with transformational policy options as follows:

1. Create a statewide insurance pool or other alternative risk transfer mechanism to cost-effectively manage power generation project credit risk exposures.

2. Allow California IOUs to benefit from leveraged equity investments in the same manner as private investment fund.

3. Modify market structure to expand use of clearinghouses.

Four additional recommendations cover incremental changes that could occur within the existing market structure:

1. Differentiate Risk by Project Size and Technology.

2. Establish the value of CPUC oversight during the IOU procurement process.

3. Encourage securitization and self-insurance of power purchasers.

4. Accelerate long-term contracting.

Chapter 1: Introduction

This report provides a summary of the June 27, 2006, workshop on credit policies held by the California Energy Commission (Energy Commission). It summarizes information and comments presented at the workshop and in subsequent written comments. It also makes three recommendations that address structural market issues, designed to provide the State of California with transformational policy options. Four additional recommendations cover incremental changes that do not appreciably change the existing market structure.

This workshop examined credit policies imposed on new generation projects in California, with particular emphasis on renewable generation. The workshop brought interested parties together, especially investment bankers, power plant investors, portfolio managers, insurance companies, risk managers, developers, and investor-owned and municipal utilities, to:

- Review credit policies in California and other representative states.
- Characterize how California's current credit policies contribute to project costs in real dollars.
- Explore the extent that these policies impede generation project development, including renewable projects.
- Identify a set of prudent solutions that would satisfy present credit policies while lowering the effective cost of capital, including step-in rights, insurance products, risk pooling, and reducing credit requirements.
- Identify topics for future research and establish next action steps.

The report is organized as follows:

- **Chapter 2** provides a background and regulatory discussion of credit requirements.
- **Chapter 3** identifies workshop participants and summarizes the presentations.
- **Chapter 4** summarizes the written comments filed after the workshop.
- **Chapter 5** outlines the results of an effort to model the aggregate effect of credit costs to specific projects in California.
- **Chapter 6** provides a summary of workshop findings.
- **Chapter 7** presents three market transformation recommendations and four incremental recommendations to be considered by the State of California.

Chapter 2: Background

Overview of Credit Requirements

Power generation projects face many hurdles during their development and do not always result in operational facilities. Utilities signing power purchase agreements (PPAs) with power plant developers face the real prospect of *contract failure* when energy projects fail to achieve commercial operation. This risk is not consistent across all North American utilities, however--many utilities experience few or no failures, while others experience extraordinarily high rates of project failure.[1]

Large power procurement efforts conducted over many years experience an overall contract failure rate of 20-30 percent across the United States. Failure rates of 50 percent or higher may occur for projects employing technologies not yet proven through widespread commercialization or, like many in California, face siting, permitting, resource supply, transmission, or other barriers to development.[2] California utilities have relevant experience with energy project contract failure. For example, during the Pacific Gas & Electric (PG&E) bankruptcy, the utility collected more than $500 million in contract termination payments from Duke, Enron, and Mirant.[3] California utilities also have experience with power sellers defaulting, or threatening to default, on their supply agreements during the energy crisis of 2001.[4]

Since 2001, power purchasers have instituted a range of approaches to lessen the effects of contract failure. Some of those instruments reflect utility experience with the merchant plant and wholesale trading era of the 1990s. During that period, energy trading companies entered into PPAs that used mark-to-market accounting[5] to estimate the contract's security requirements. This accounting method, developed for wholesale power sales between entities with substantial credit and cash reserves, may not fit the new market of smaller power projects and special-purpose entities (SPEs).

Other instruments employed today include performance specifications, maintenance obligations, heat rate guarantees, and credit postings.[6] Developer creditworthiness is a major factor used by power purchasers to determine the risk of contract failure. The functional result of these aggregate credit requirements is the tying up of billions of dollars in captive, non-performing capital. Southern California Edison (SCE) acknowledged the negative ramifications of withholding so much capital from the market as protection against contract failure.[7]

Credit requirements establish the creditworthiness of developers at different phases of project life. Power project developers must provide evidence of good credit as a prerequisite to entering into PPAs with utilities and maintain good standing while delivering power.[8] Regulators, policymakers, and developers share a concern that overly stringent credit requirements may restrict competition among power suppliers and raise the price of power.[9]

Examples of credit requirements faced by developers include pre-contract-phase bid deposits, financial information for bid evaluation, construction-phase development security, and collateral during operation. The initial bid deposits may be required before a developer responds to a Request for Offers (RFO) to provide power. Collateral amounts and credit requirements vary widely across utilities and adhere to no standard. However, California's major utilities seem to be establishing more similar requirements.[10] **Table 2-1** lists the basic types of credit requirements.

Table 2-1. Types of Credit Requirements

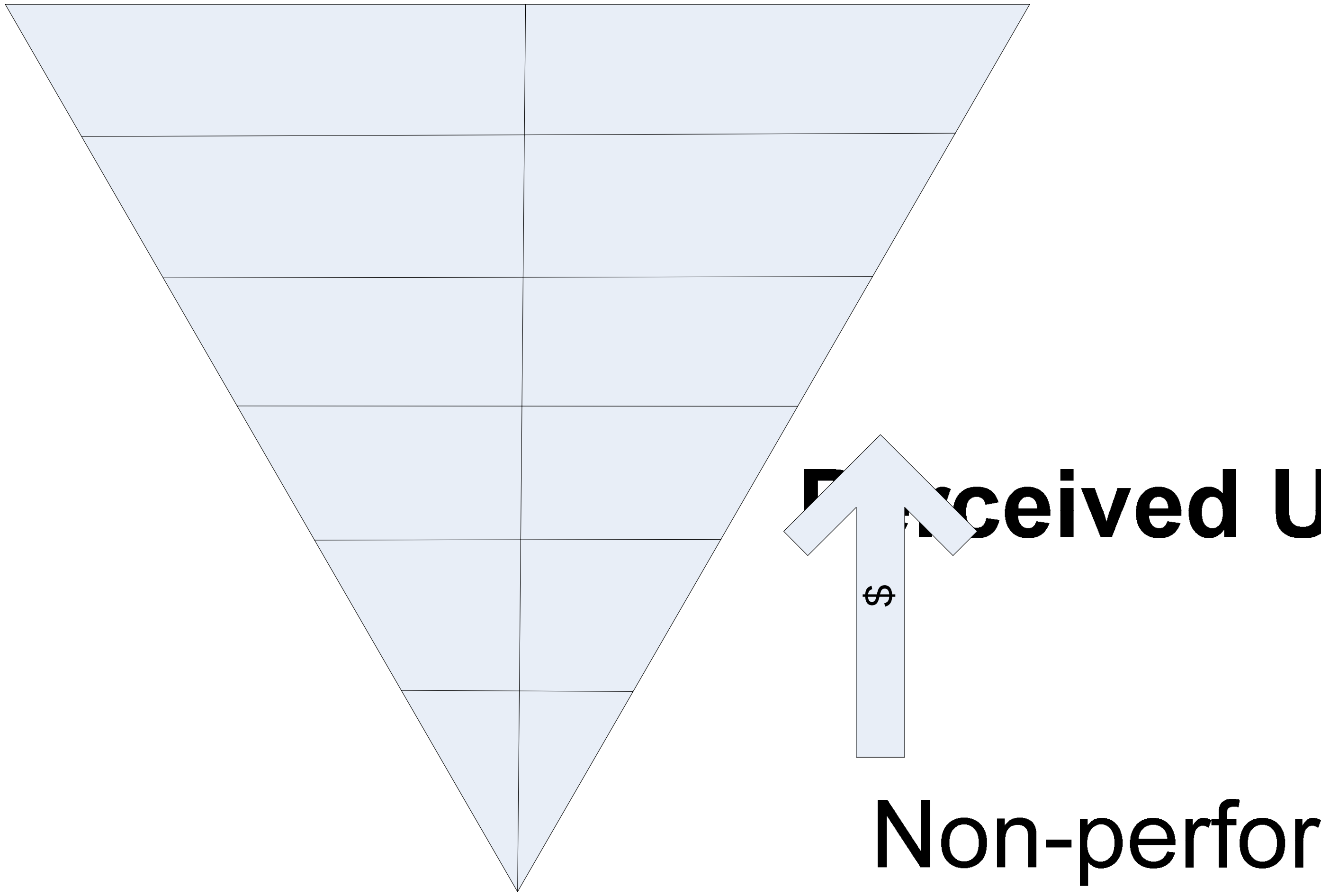
Requirement	Timeframe
Bid Deposits	During bid evaluation process, due either at bid submittal or upon short-list selection
Financial Information	Used for bid evaluation, during project development and throughout operation
Development Security	From contract signing to commercial operation date
Collateral During Operation	From commercial operation date to contract termination

Source: KEMA, July 2006.

Security amounts increase as the project progresses through the procurement process. As the utilities perceived commercial risk from the project increases, the amount of security the project is expected to post is correspondingly increased. The figure below shows an inverted pyramid, with credit requirements starting out as small at the bottom (proposal security) and ending up at the highest level of security, operational collateral. Chapter 5 quantifies credit requirements for various utilities, but to give an example, PG&E's credit requirements from its 2006 renewable RFO would be the following for a typical 100 MW wind project:

- Bid deposit of $3/kW due on short-list: $300,000
- Development security of $20/kW on CPUC approval: $2 million
- Operational collateral of 12 months revenue: $20 million

The utility increases its credit requirements because it perceives its risk to be increasing at each stage of the project development process. At the initial stages, the risk to the utility involves whether or not a project bidding into an RFO is in fact presenting the bid in good faith, and is prepared to negotiate a PPA. The utility's risk is the time and effort placed in reviewing that bid. Once a PPA is approved by the commission, however, the utility's perceived risk increases. Energy (and perhaps capacity) is expected to be online at the scheduled date. The utility has signed a binding contract that has financial implications, such as imputed debt. Finally, once the project comes online, the utility perceives its risk at much higher levels still. Lack of project performance now means the utility must acquire power at market prices, which may be far higher that the contract price.



From the developer's perspective, risk is defined in much different terms. Project risk actually declines over time, as the project acquires all necessary permits and construction finance, is successfully completed, and finally interconnected to the transmission grid. Thus the "ratcheting up" of collateral requirements by utilities runs counter to the financial expectations of project developers, establishing the potential for conflict.

Role of State Agencies in Credit Requirements for Energy Procurement

California Energy Commission

The Energy Commission aims to promote a dialog between experts in energy project financing and key California policy makers to better understand the critical link between bankers and regulators in the project development process. Past workshops and studies have been used to share information and perspectives on the topic.

On January 16, 2003, the Energy Commission hosted an introductory workshop on the fundamentals of project finance. The 2003 workshop, sponsored by the U.S. Department of Energy, provided information on U.S. energy finance fundamentals from the policymaker's perspective. Other topics addressed included the risk, valuation, and capital markets that affect financing of both merchant power plants and projects for electric or natural gas transmission. The 2003 workshop was an initial meeting to provide the necessary foundation for possible future workshops focusing on developing solutions to problems that thwart financing the construction of energy projects.

A second workshop on energy project finance options was held on May 6, 2004. The 2004 workshop focused on financing power production and transmission projects. The 2004 meeting was conducted in preparation of the Energy Commission's *2005 Integrated Energy Policy Report (IEPR)*. The *2005 IEPR* states that the current process for procuring renewable resources is overly complex, and the procurement process in general needs to be more open and transparent.[11]

Regarding procurement of renewable energy, the 2006 Renewable Energy Investment Plan[12] shows the efforts made by investor-owned utilities (IOUs) to comply with the Renewables Portfolio Standard (RPS) goals before issuing RFOs in 2005, and how RFOs sometimes allow early stage projects to bid, despite a lack of siting or permitting clearance or insufficient financing or capital.

The June 27, 2006, credit policies workshop and this report will be used as background information to prepare the *2007 IEPR*. The focus is on lowering the cost of capital for generation projects, especially renewable resources, and California credit policies.

More detailed studies previously published by the Energy Commission address the risk of contract failure for renewable energy projects[13] and the cost of credit requirements in California and elsewhere in the West. These studies indicated that projects with low capacity factors—intermittent resources such as wind or solar power--are further burdened by credit requirements based on nameplate capacity. Costs of roughly $1 per megawatt-hour can be attributed to operating collateral requirements.[14]

Future joint workshops of the Energy Commission and CPUC will also continue to provide information and perspectives on the issue of credit policies.

California Public Utilities Commission

A fundamental goal of the CPUC is to ensure that customers of the IOUs and other load serving entities (LSEs) receive reliable electric service through cost-effective, environmentally sound, sustainable, and competitive procurement of electric generation capacity. Key elements of the CPUC policies for procurement of electric generation include:

- The California Energy Action Plan (EAP II), which establishes a preferred loading order of resources with highest preference for energy efficiency and demand response.[15]
- Review and approval of the IOUs' Long-Term Procurement Plans (LTPPs) along with the Energy Commission's electricity demand forecast.

- Establishment of Resource Adequacy (RA) procurement obligations whereby each jurisdictional LSE must acquire the resources needed to serve its own customer load plus a 15-17 percent planning reserve margin.

The CPUC is responsible for monitoring IOU procurement activities, including renewable resources.[16] Implementing short-term and long-term integrated procurement plans involves CPUC monitoring of compliance with the loading order and progress towards the state's RPS goal of 20 percent by 2010. RPS legislation requires each IOU to procure a minimum quantity of electricity from eligible renewable resources. Monitoring the IOU actions related to credit and collateral policies also occurs as part of the CPUC's 2006 Long-Term Procurement Proceeding (R.06-02-013).

Power procurement normally requires establishing a transmission interconnection and transmission network reinforcements or upgrades. However, the CPUC does not have the authority to require the IOUs to fund upfront costs of interconnections for generators or network upgrades required for new generators. These costs are normally the responsibility of the generator.

Costs of bringing transmission service to renewable power generators are treated differently than those of traditional generators. Public Utility Code Sec. 399.25 allows the CPUC to make a determination on specific transmission facilities necessary for the state to achieve its RPS goals. The CPUC has taken multiple steps to fairly allocate new transmission costs to developers of renewable projects triggering the transmission need. In D.04-06-013 (June 2004), the CPUC adjusted the bid-ranking process to recognize opportunities to share the costs of interconnection facilities across multiple projects, and in D.05-07-040 (July 2005), the CPUC directed the IOUs to assign the costs of large transmission upgrades that would be used by multiple projects on a pro-rata basis during bid evaluation. Recent actions by the CPUC allow IOUs to recover the costs of such transmission facilities if determined to be needed for meeting the RPS goals (I.05-09-005; D.06-06-034, June 15, 2006).

The CPUC is moving toward requiring the IOUs to submit renewable energy procurement plans and issue RFOs on a calendar year solicitation cycle. Sponsors of eligible generation projects are to be selected by each IOU between October and December.

The California electricity market structure is developing features to ensure resource adequacy (RA). As part of this effort, the CPUC recently required SCE and PG&E to acquire new power plants as part of a "limited and transitional" procurement mechanism for meeting 2009 needs.[17] Under the "limited and transitional" procurement structure, IOUs become responsible for procuring new generation, as well as power, within the distribution service territory. This procurement structure splits the capacity and energy provided by new projects into two contracts. The costs of new generation capacity are to be allocated to all customers in the service territory, including all bundled-service customers, direct access customers, community choice aggregation customers, and others who are within the distribution service territory of an IOU but take service from a local publicly owned utility. The separate energy component of new projects is to be auctioned. Periodic auctions will allow separate entities, including investors, to manage and market the energy component of the contracts.

California Independent System Operator

All participants in the California Independent System Operator market, including generators selling to the California ISO grid, are subject to financial review by California ISO for creditworthiness.[18] The California ISO Credit Policy and Procedures Guide (June 2006) and California ISO Tariff describe the information required to build an unsecured credit limit and the forms of financial security that may be posted to back transactions. In addition to satisfying the credit requirements, power plant developers also pay the direct costs for interconnection.

Costs that must be shouldered by prospective generators in California ISO territory include non-refundable costs of interconnection studies and direct interconnection facilities for transmission, and refundable costs of upgrades necessary to maintain transmission network reliability. Interconnection studies normally cost between $100,000 and $250,000.[19]

The costs of facilities depend on location and timing. Since changes to the transmission grid are often needed before remotely located generators can interconnect (especially wind or geothermal), the costs experienced by generators can change if precedent facilities do not materialize on schedule. California ISO uses a queuing process to establish project sequence and estimate interconnection costs, but if a higher-queued facility drops out, a generator may be exposed to a dramatic change in the costs of interconnection or reliability upgrades. Because these costs vary dramatically depending on infrastructure in the project area and the timing or success of other projects in the queue, they can jeopardize projects that might otherwise be viable.[20] California ISO suggested that a clustering process could be used as an option to the queue in geographic areas where multiple projects are proposed.[21]

Chapter 3: Workshop Participants and Presentations

State of California

- Joseph Desmond, (Former) Undersecretary of Energy Affairs
- John Geesman, Commissioner, California Energy Commission
- Jeffrey Byron, Commissioner, California Energy Commission
- John Bohn, Commissioner, California Public Utilities Commission
- Eric Saltmarsh, Executive Director, Electricity Oversight Board (EOB)

Panel 1 – Issues for Private Power Developers

Overview: Ric O'Connell, Black & Veatch
Moderator: Steve Zaminski, Starwood Energy Group

- Kevin McSpadden, Attorney, Finance, Milbank, Tweed, Hadley & McCloy LLP
- Thomas King, Executive Vice President, Finance, U.S. Renewables Group
- Joe Greco, Vice President, Western Development, Caithness Energy LLC
- John Seymour, Executive Director, Florida Power & Light Energy
- John Tormey, Senior Counsel, Constellation Energy Group, Inc.
- Tom Lumsden, Senior Managing Director, FTI Consulting
- Tom French, Director of Loads and Resource, California ISO
- Fong Wan, Vice President, Electric Resources, PG&E
- Pedro Pizarro, Senior Vice President, Power Procurement, SCE
- Teresa (Terry) Farrelly, Vice President, Electric & Gas Procurement, San Diego Gas & Electric (SDG&E)

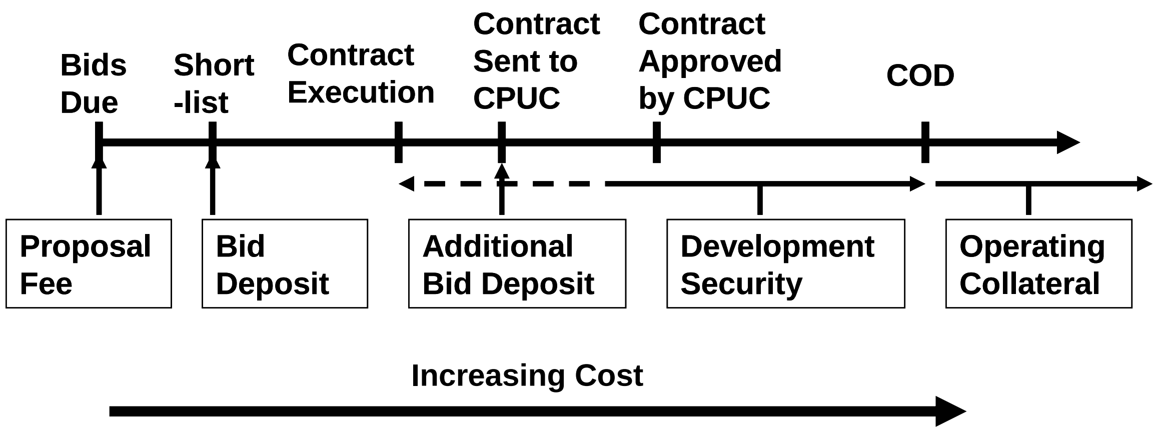
Panel 2 – Alternative Approaches to Credit Requirements

Moderator: Gary Ackerman, Western Power Trading Forum

- Kevin McSpadden, Attorney, Finance, Milbank, Tweed, Hadley & McCloy LLP
- John Buehler, Managing Partner, Energy Investors Fund
- John Flory, President, North American Energy Credit and Clearing Corp. (NECC)
- Joe Greco, Vice President, Western Development, Caithness Energy LLC
- John Seymour, Executive Director, Florida Power & Light Energy
- John Tormey, Senior Counsel, Constellation Energy Group, Inc.
- Fong Wan, Vice President, Electric Resources, PG&E
- Pedro Pizarro, Senior Vice President, Power Procurement, SCE
- Lad Lorenz, Vice President, Regulatory Affairs, Southern California Gas and SDG&E
- Russell Read, Chief Investment Officer, California Public Employees' Retirement System (CalPERS)
- Curtis Kebler, Vice President, U.S. Power Trading, Goldman Sachs
- Partho Ghosh, Senior Vice President, Financial Risk Products, Marsh Alternative Risk Solutions, MMC Securities

Credit Requirements Overview

If a contract fails—a project is not completed on time or does not deliver according to contract—a utility may be forced to procure energy through the wholesale market. California's IOUs and power plant developers disagree on the likelihood of contract failure and project underperformance, but some type of security or collateral is currently required in advance, to compensate the utility for this risk. From the utility's perspective, this risk—and therefore the cost of associated mitigations—increases as the project passes through the stages of development and commercial operation, as noted below:



Four types of credit requirements are described below.

Bid Deposit. Types of collateral that satisfy bid credit requirements include cash, a letter of credit, or other collateral. Developers are reluctant to provide cash because it sacrifices equity that is especially valuable early in the project life, and a letter of credit may similarly reduce the borrowing capacity of the project and may not be available to smaller developers. In some cases, the collateral thresholds may be adjustable depending on the credit rating of the developer. Bid deposit requirements tend to discourage weak proposals.

Development Security. Development security is collateral to ensure that a project is built and delivers power on schedule. Development security can be used by the utilities to cover wholesale market purchases of power and potential penalties that may be levied by the CPUC in the future for failure to meet RPS requirements.[22]

Financial Information. Power purchasers require varying levels of detail in their financial disclosure requirements, to establish a seller's credit rating and history. In some cases, the power purchasers also require a pro forma project budget.

Operating Collateral. Operating collateral covers damages caused by lack of performance, project owner default, or contract termination. The requirements for operating collateral are especially variable. Fixed dollar amounts based on months of revenue, the nameplate capacity, or the expected generation are typically used. Past solicitations have also required the operating collateral to vary depending on the market prices of replacement power (a "mark-to-market" basis).[23] Sometimes, operating collateral is "non-liquid," where the utility gains the right to either "step-in" and run a project or take over the project's subordinated mortgage in the case of underperformance.

Workshop presentations made by Black & Veatch and Milbank summarized surveys of credit requirements set forth by western-state utilities as of June 2006. Some utilities determine these requirements on a contract-by-contract basis, but the major California utilities define them in their RFOs. Black & Veatch highlighted the differences in approaches:[24]

- Bid deposit requirements range from zero to $3/kW for SDG&E, with similar "reasonable" levels for PG&E and SCE ($3/kW), to high levels for Los Angeles Department of Water & Power ($5,000/kW).
- Relatively detailed levels of financial information, including a pro forma project budget, is required by PG&E, SCE, and LADWP, but not SDG&E.
- Development security requirements are unspecified for LADWP, range from low for SCE ($20/kW) and PG&E ($36/kW after construction) to high for SDG&E ($10/MWh), and are variable for PacifiCorp, which requires two years of project revenue.

Penalizing low capacity factor technologies is a recognized concern. Black & Veatch showed that deposit and collateral requirements based on nameplate capacity can disadvantage smaller projects or projects that generate power intermittently, such as wind or solar.[25] PG&E acknowledged the variations in collateral costs for projects using different technologies. Renewable energy projects with lower capacity factors tend to have a higher collateral cost per kWh. PG&E indicated a willingness to establish a collateral structure that results in more comparable requirements from project to project, regardless of the technology, in future solicitations.[26]

Other factors penalize small or renewable projects. For example, operational collateral requirements using "mark-to-market" accounting are probably inappropriate for renewable generators because of the resources required and the lack of a liquid market for renewable energy.[27] Additionally, use of collateral thresholds for development or operation can favor larger developers because the threshold level may be a large portion of the overall cost for a smaller project but a negligible fraction of a large project's cost.

The cost of operating collateral on a per-megawatt-hour basis appears to be small, averaging about $0.50/MWh, ranging up to about $1.50/MWh.[28]

Lowering the Effective Cost of Capital for Generation Projects

Why do credit requirements warrant scrutiny? The costs of credit requirements are more complex than, for example, simply the carrying cost of a letter of credit because they adversely impact the borrowing capacity of the project. The carrying cost of the credit affects cash flow, out-of-pocket cash flow, and debt capacity. These costs translate into higher electricity rates; the State of California would pay $2 billion less for power annually if electricity rates were at the national average.[29]

Starwood indicated that credit requirements of the California utilities add approximately 6 percent to the capital cost of a typical wind project, and 9 percent to the capital cost of a natural gas-fired peaker project. This reduced borrowing capacity increases capacity payments by up to 8 percent.[30] Caithness confirmed that the above levels are similar to their in-house estimates of the opportunity cost of California's credit requirements and noted that total collateral requirements for a 350-MW gas-fired plant they are building in another state are lower than the same requirements for a 40-MW geothermal plant modeled in the study presented to the workshop.[31] Follow-up work by Black & Veatch for the workshop showed the cumulative cost of the credit requirements to be roughly 2 percent of project cost; this is shown in Chapter 5, below.

The Starwood presentation provided observations from the perspective of a developer of peaker power projects. Peaker power projects are useful for generating power capable of on-demand dispatching, unlike the intermittent nature of non-hydro renewable sources. Starwood estimates that establishing a new peaker plant in California is two times more costly than elsewhere in the nation. Despite these costs, SCE noted that Starwood apparently sees value in California because Starwood has purchased five peaker plants in California.[32] Starwood is building a sixth plant because the IOU does not recognize RFO bids from existing facilities.[33]

FPL is presently not bidding on California RFOs because of uncertain development costs. Caithness believes that California's credit requirements are more burdensome than in northeast and eastern areas of the country.[34, 35]

Starwood believes that excessive credit requirements have the unintended side effect of making projects more susceptible to failure by increasing the financial risks for developers. The requirements also stunt competition by forcing smaller projects and entrepreneurial developers to the sidelines.[36]

Other limitations in the procurement process are a concern to developers, but are outside the scope of the workshop. For example, the RFO process tends to favor new or green-field projects rather than encourage a change in use of existing facilities.[37] In addition, utilities often use proprietary resource planning data (gas and electric price forecasts) and non-quantifiable or non-transparent criteria in the evaluation of bids. Because procurement data and criteria are not available to bidders, the CPUC procurement process involves some level of subjective judgment in project selection.[38, 39]

Perspective of the Investor-Owned Utilities

Presentations by the IOUs identified the possibility of loss that can be associated with counterparty default, and that contract failure can be a result of either underpayment or underperformance. The IOUs lower these credit risks by requiring collateral and by adding terms that enable the utility to procure replacement on the open market, if needed.[40] Although the focus of this discussion was on power procurement by the IOUs, PG&E notes that it is also a major power seller during certain times of the year. As such, PG&E tries to structure its agreements with sellers and buyers so that the credit terms and provisions are symmetrical.[41]

The SCE presentation provided a chart of the evolution of credit requirements to show how power procurement during the “post-crisis” years beginning in 2003 (after resolution of utility bankruptcies) involves more stringent credit requirements than in previous decades. The increase in credit requirements coincided with a period of improving credit ratings for the IOUs.[42] However, when asked whether more stringent credit requirements help to improve the credit ratings of the IOUs, there was no consensus that they do.[43]

The volatility of operational collateral requirements is a recognized concern of developers and lenders. Operational collateral can be posted on either a mark-to-market basis or on a portion of revenue basis. SCE and SDG&E have both found it difficult to secure operating collateral on a mark-to-market basis on renewable projects.[44] Lenders are generally not receptive to the variability of mark-to-market collateral requirements. All three IOUs indicate that their credit requirements are placing less emphasis on mark-to-market collateral requirements.

SCE and SDG&E state that operational credit in the form of liquid collateral (cash, letter of credit, surety bonds, or guaranty from investment-grade parent) can be supplemented with other assurances to discourage contract default. Use of a special purpose entity (SPE) or a variable interest entity by a developer may provide security to the utility as it may insulate against parent company losses or facilitate liquidation or transfer of the project assets to the utility in case of contract default. Other contracting approaches that provide or allow for transfer of the project to the utility, for example through exclusivity or a lien, also serve as credit to assure that performance will be protected. SDG&E also sometimes pursues step-in rights for larger projects.[45]

SCE believes that changes in its 2006 procurement effort are leading to more flexibility in collateral options, which should increase incentives for new generation offers. SCE also believes that new contracting approaches may also come as a result of potential development of “capacity markets” within California or capacity product development.[46] A capacity market would require utilities to procure generation capacity to augment power procurement. This would provide developers an incentive to offer generation capacity to the utilities while offering power, giving utilities wider ability to control the availability of generators through capacity and/or power purchase agreements.

Alternative Approaches to Credit Requirements

The presentations made by developers offer options for adjusting the credit requirements. Developers and the financial community generally suggest that less stringent credit requirements or restructured insurance against contract failure might help to reduce the cost of credit requirements and make more projects viable.

Reducing Bid Deposit Requirements

Minimizing bid deposit requirements has the effect of expanding available capital to projects because the high upfront bid costs can adversely affect the borrowing capacity of a project. Bid deposits are normally set on nameplate capacity, which tends to disadvantage wind and other low-capacity-factor technologies.[47] Milbank believes that bid deposit requirements should be reduced because of the oversight provided by CPUC during procurement, and the least-cost, best-fit methodology used in the procurement process.[48]

The CPUC encouraged IOUs to reduce bid and deposit requirements in the 2006 RFOs, and the credit requirements within the IOU's latest RFOs have changed accordingly. As part of the 2006 procurement cycle, the CPUC considered but rejected proposals to uniformly limit bid deposit and development security requirements and instead guided the IOUs to employ "reasonable" criteria,[49] where reasonable credit requirements are those that do not prevent otherwise viable projects from coming forward. The CPUC expects to consider the level of collateral required by the IOU at the time of power procurement when determining whether RPS penalties are warranted (May 25, 2006, D.06-05-039, pp.34 to 38; R.04-04-026). This means that if an IOU eventually fails to comply with RPS goals because of overly stringent credit requirements, the CPUC may levy more severe non-compliance penalties.

Reducing Development Security Requirements

Development security requirements could be alternatively satisfied with step-in rights, subordinated security interest, assignment of fractional ownership (buy-down) under project equipment warranty, and payment of daily delay charges. Construction lenders serve as a backstop and provide oversight to curb excessive development costs or schedule underperformance. Major equipment installed at the project is normally covered by a warranty.[50] SCE, however, believes that it is difficult to place a value on step-in rights, construction lender backstop, major equipment warranties, or subordinated security interests.[51]

The CPUC recently offered to consider the level of collateral required by the IOU at the time of power procurement when setting any future RPS penalties, as noted above.[52] In general, CPUC oversight during all types of procurement helps to minimize the risk of contract failure because active CPUC involvement may allow IOUs to recover procurement losses with ratemaking. The development community and IOUs would benefit if the CPUC could clarify how exemptions from RPS penalties will be determined.[53]

Commissioner Bohn asked about whether the risk of non-performance would be different for a project developed directly by an IOU, when compared to that of an independent power producer. SCE responded by noting that the CPUC provides more direct oversight of an IOU project, and the CPUC would have the discretion to determine what portion of costs the IOU shareholders are able to recover from ratepayers. The risk of utility-owned generation would be carried on the balance sheet of the IOU and would affect the IOU's credit rating directly. This represents a different business model than the IOUs are currently following, where third-party developers rather than IOU shareholders or ratepayers provide the backstop collateral.

There was a recommendation for additional study by the Energy Commission or CPUC to clarify the value of the risk-mitigating effects of financing from lenders, equipment warranties, and other routine forms of insurance. The value of these features should be considered by IOUs to reduce development and performance security requirements.[54]

Reducing Operational Collateral Requirements

Operating collateral requirements of the California IOUs are among the highest in nation, and these costs are passed on to ratepayers through higher contract prices. The alternative security structures that could be used to satisfy operating collateral requirements are step-in rights, subordinated security interest, terms requiring reinvestment of insurance proceeds or use of insurance proceeds for buy-down of contract capacity, and assignment of a fractional ownership (buy-down) under project equipment warranty or from a guarantee of availability (especially for wind turbines). Operating collateral requirements could also be reduced to reflect the protection provided by the reserve capacity held by IOUs as part of resource adequacy requirements, the oversight of the project financing lender, equipment warranties, and insurance.[55]

Subordinated security interest and assignment of the equipment warranty payments could be used to protect the utility in the case of project equipment malfunction or underperformance. In this approach, the utility's risk could be reduced during early periods of project life by assignment of warranty payments and, later in project life, subordinate security interest could be transferred to the utility for operating collateral.

Energy projects are commonly funded through the use of non-recourse loans.[56] Non-recourse project financing means that the loan is secured only by project collateral and cash flow, rather than collateral unrelated to the project. As a result, most energy project loans are subject to a high level of scrutiny by the lenders. A high level of scrutiny provided by the financer helps to minimize the risk of default during development and operation.

Milbank and EIF believe that performance risk can be minimized with long-term agreements on fuel supplies and warranties on energy delivery infrastructure. It is possible to provide non-recourse financing for energy projects without exposing investors to fuel price volatility.[57]

Step-In Rights as Operational Collateral

Step-in rights could be used to protect the power purchasers in the case of a default, although this depends on whether the senior lender would agree. The purchaser would need to assume all of the project's obligations to the lenders and could be forced to shoulder the project's liabilities. Offering step-in rights can be further complicated if the power purchaser itself is not creditworthy, or if the purchaser does not have the capacity to operate or maintain the plant.[58]

Step-in rights cannot usually be transferred to the power purchaser in the case of a bankruptcy.[59] Lenders normally would rather sell the failing project than work with a step-in operator. Step-in rights would need to be developed with lenders and generators on a project-by-project basis to accommodate the power purchasers who need the project to operate. Determining the value of step-in rights as an alternative to collateral is also case-by-case.

Securitizing Risk to Insure Power Purchasers

Real-time power prices can jump by a factor of 10 during a 24-hour period. This volatility is largely due to the transient nature of electricity–it is a commodity that cannot be stored. MMC Securities showed how this causes power purchasers to demand high-value collateral for risk protection. If the power procurement process imposes the collateral requirements of higher-risk projects on all projects, the costs of lower-risk projects are driven up and eventually passed on to ratepayers.[60]

MMC Securities presented the concepts of securitization and credit support to pool the risk of projects. Through securitization or creation of credit derivatives, power producers may be able to trade credit risk to entities that have access to capital at a lower cost, such as power purchasers or insurers with higher credit ratings. Most power producer companies are rated as "junk" or below investment-grade. To make credit derivatives more attractive to investors, support can be added in the form of power price protection, default protection, or trade credit insurance.[61]

MMC Securities noted that investors (such as hedge funds) are increasingly providing capital for credit derivatives like credit-default swaps, which provide default risk coverage beyond what traditional insurance companies would cover.[62] For example, CalPERS invests in a nationwide Credit Enhancement Program that uses CalPERS' investment-grade credit rating to underwrite municipal infrastructure projects around the nation.[63] MMC Securities also identifies counterparties in power purchase agreements to take over the obligations of the seller by generating power for the buyer, if necessary to check underperformance.[64]

An insurance product that provides default protection and power price protection across an entire utility or the state may create cost efficiencies attractive to utilities, as long as it continues to encourage project performance.[65] SCE, however, noted it would not be possible to develop credit derivatives for projects that are needed for local reliability. Resource adequacy and local area reliability requirements depend on the physical configuration of the electric system.[66]

Commissioners Bohn and Geesman recognized that the default risk of multiple power purchase agreements could be pooled by power purchasers across multiple contracts to minimize the need for power sellers to post large amounts of operating collateral. Executive Director Saltmarsh of the EOB noted this would improve the value of credit requirements without increasing their costs.

Encouraging Financing by Intermediaries

The presentations by Energy Investors Fund (EIF) and CalPERS showed a robust level of available capital for energy projects in 2006. A high level of equity for transmission projects, fuel projects, and renewable energy generators is available and is expected to grow. CalPERS is funding clean energy technologies and renewable energy through investment in individual projects and by investing in the equity and debt of developers; CalPERS also provides credit enhancement for qualified municipal utility projects.[67] EIF indicated about 700 private equity funds presently focus on the power and energy sector. EIF and CalPERS both stated that power purchasing utilities should be able to access this capital for financing utility-owned renewable projects.

Along with generation projects, the private sector, lenders, and equity sources are looking to develop fuel supply projects (such as coal-to-liquids, ethanol, biodiesel). Incentives for such projects have come from the federal Energy Policy Act of 2005 (EPAct). This provides capital for energy assets and companies through many channels including venture capital, hedge funds, and possible buyout opportunities.[68]

EIF explained how tax credits and EPAct incentives can be used to make a renewable project more attractive to financers.[69] For example, developers may monetize tax credits by electing to sell interest to an investor through a limited partnership (LP) or limited liability partnership (LLP) and by sharing cash flow and the benefits of the credits with the partnership. In biomass power generation projects, a lease structure may also be created for sharing the benefits of the credits. EIF notes that because the federal production tax credit (PTC) for wind energy is subject to renewal every two years, a more stable investment climate would be established if the tax credits could be established for a longer term.

The Goldman Sachs presentation focused on changes to the structure of the California electricity market contemplated by the CPUC in early 2006.[70] The CPUC recently ordered SCE and PG&E to procure incremental amounts of new generation capacity for 2009. CPUC approved the "limited and transitional" procurement strategy described in Chapter 2, above, after considering alternate market structures more similar to the traditional power procurement approach.[71]

Goldman Sachs noted that because a higher credit rating enables a lower cost of capital, a traditional form of utility procurement constrains the available approaches to meeting credit requirements. Use of intermediary financing could allow more flexible credit arrangements.[72] The North American Energy Credit and Clearing Corp (NECC) presentation expanded on this by providing an overview of efficiencies provided by clearinghouse markets. Introducing forward contracts and physical clearing would allow more efficient use of capital by power purchasers and sellers by ensuring a more consistent market.[73]

SCE recognized that a clearinghouse could be beneficial for the wholesale energy market, but that such a mechanism's ability to lower the cost of new generation is unclear. The IOUs suggest that if an intermediary is used for renewable projects, it must also allow the power purchaser to capture the benefits of resource adequacy accounting credits, renewable energy certificates (RECs) or green tags, and emission reduction credits (ERCs), which are not currently easily tradable.[74]

NECC believes that replacing one-on-one contracts between generators and power purchasers with physical clearing would enhance liquidity and pool the risks of individual transactions, which could reduce the need for collateral.[75] Developers of small projects caution that any physical clearing market should be structured to allow full participation of small generators (under 1 MW) that wish to sell renewable resources, including credits for resource adequacy and RECs.[76] Florida Power & Light Energy, a developer of larger projects, believes that the role of the clearinghouse could be played by the utilities since they currently develop the pool of suppliers and a portfolio of contracts to diversify risks.[77]

Developers are not restricted from choosing to work with bankers to access capital at the time of responding to an RFO and allow the bank to back risks and partner with power purchasers.[78] Developers recognize, however, that few sponsoring investors are willing to back projects that depend on volatile forward price levels or short-term power purchases. As a result, access to investment capital is more straightforward for base load projects than it is for peaker and renewable projects. A greater level of RFO activity for long-term and base load power purchases would facilitate developer access to capital.

Chapter 4: Written Comments

Written comments were provided after the June 27, 2006, workshop from IOUs (SCE and PG&E) and one project developer (RCM Digesters).

SCE and PG&E both recognize that there is a cost to assuring performance of power sellers. Written comments filed after the workshop clarify that SCE and PG&E are committed to exploring alternative approaches to reduce performance risk. SCE notes that its credit requirements are changing to provide more flexible collateral options. However, SCE feels that its current credit requirements have not posed a barrier to developers or impeded execution of contracts. As a result of SCE's four all-source solicitations and two RPS solicitations between 2002 and 2005, SCE has contracted with both small and large generators, including renewable projects.[79] Similarly, PG&E believes that good projects of all sizes will come to fruition, despite present collateral requirements, and that PG&E's credit policy is appropriate for the current energy market.[80]

PG&E's current approach to credit requirements is a result of bankruptcy filings and contract rejections in recent years. PG&E points out that most bidders into its all-source and renewable solicitations are either non-investment grade entities or "special purpose entities", or SPEs, formed for the sole purpose of generating power.[81] PG&E adjusts the requirements based on the credit rating of the seller. Because the workshop focused on lesser-capitalized entities, PG&E requests that the Energy Commission conduct further analysis of the different cost of credit for lesser-capitalized entities and investment-grade developers. Comparing the two may reveal a negligible cost of credit for investment grade developers.[82]

RCM Digesters[83] filed written comments giving the perspective of a small company developing small-scale renewable projects. RCM Digesters agrees with Black & Veatch and Starwood that security deposit requirements designed for large projects hinder the development of projects in the range of 1 MW and below. The risk to the IOU of a project failing increases exponentially with the size of the project, and contract or performance failure of a small project is much less likely to damage an IOU than failure of a large project. For example, a 30 percent probability of failure for one 100 MW plant presents greater risk than 30 percent probability of failure among ten 10 MW plants, because 70 MW is likely to remain online.[84] As a remedy, RCM Digesters proposes that security deposits of all kinds should be scaled according to the square of the size of the project. Large projects should pay high levels of security, and smaller projects should be required to provide minimal security.[85]

RCM Digesters addressed other difficulties faced by small generators in the power procurement process. For example, PG&E's 2006 protocol for RPS solicitation excludes projects under 1 MW of aggregate generation, and, for projects larger than the state net metering cap of 100 kW, does not currently buy back excess electricity generated at a customer's site. This 900 kW gap continues despite the loading order of the Energy Action Plan that clearly prioritizes distributed generation before additional centralized generation. The security deposit requirements and exclusion of projects under 1 MW are barriers especially to small-scale fuel cells (which optimally run continuously) and anaerobic digesters that produce electricity as a function of the onsite fuel available. Both technologies are prioritized by state policy, but are not economically viable because they must depend on power purchase agreements and are normally excluded from the IOU procurement process.[86] RCM Digesters believes that facilitating participation of small generators by eliminating credit requirements would help implement the loading order, and benefit California's citizens, investors, and entrepreneurs by creating opportunities for ingenuity, new ideas, and new ways of thinking.[87]

Chapter 5: Quantifying Credit Requirements

After the workshop, the Energy Commission requested additional quantification of the costs imposed on energy projects.[88] This chapter presents additional modeling work conducted by Black & Veatch on the aggregate utility credit requirement costs to a new renewable power plant in California. All references to “the original report” indicate material taken from *The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement*, CEC-300-2006-014, California Energy Commission, June 2006.

Method of Quantification

The cost of credit requirements to a power project comes from several sources:

- The bid deposit and the opportunity cost of using cash early in the development process.
- Development security required of the project.
- Operating collateral, both the carrying cost of the letter of credit as well as reduced borrowing capacity of the project.

To capture the aggregate cost of the collateral required by California utilities, the proxy renewable projects from the original report were used. The two projects, a geothermal and a wind project, were chosen because they have similar annual generation, yet different capacities and costs.

The project characteristics and assumptions, based on Black & Veatch project experience and listed in **Table 5-1**, were then used in a cash flow financial model. This model uses the financial assumptions listed in **Table 5-2** and calculates the price of power that the developer would need to charge to satisfy their equity hurdle rate.[89] While the **Table 5-2** assumptions are typical industry values, the important aspect of the modeling is that it measures the relative difference between projects with collateral and those without. Using different debt terms, interest rates, or other parameters would produce different absolute numbers, but the relative differences would be comparable.

Modeling conventional projects proved difficult, and the results are not presented here. There are several issues with modeling the effect of credit requirements on conventional generation. First, mark-to-market collateral requirements change rapidly and require knowledge of forward prices. Second, developers large enough to build a $300 million-$400 million dollar project will most likely have investment grade credit and may not have to purchase a letter of credit for some or all of the collateral requirements.

Table 5-1. Proxy Project Assumptions

Assumption	Geothermal	Wind
Project Size (MW)	40	100
Capacity Factor	85%	35%
Expected Annual Generation (MWh)	297,840	306,600
Capital Cost ($/kW)	$3,000	$1,500
Total Capital Cost ($)	$120,000,000	$150,000,000
Fixed Operations and Maintenance ($/kW-year)	N/A	$11.50
Variable Operations and Maintenance ($/MWh)	$30.00*	$7.00
Time from RFO bid to Commercial Operation Date	5 years	3 years

Source: Black & Veatch project experience
*Includes both fixed and variable O&M

Table 5-2. Financial Assumptions

Financial Assumptions	Value	Basis
IPP Debt Interest Rate (%)	8.00%	B&V estimate – 250 basis points above LIBOR.
Project Life and PPA Term (years)	20	A 20-year term is standard in the industry.
IPP Debt Term (years)	10	Standard terms for the industry is 10-15 years. Ten years was chosen to match the PTC term.
IPP Financing Fee (% of issuance)	1.50%	This is a typical value for the cost of obtaining financing.
IPP Minimum DSCR, annual average	1.35	Debt Coverage Service Ratio, ratio of cash flow to debt payments. A ratio of 1.3-1.5 is a typical standard imposed by a lender for project financing
Debt Service Reserve Fund (years)	0.5	This means the project needs to have 6 months of debt payments in reserve to ensure debt repayment should a short-term cash flow constraint occur.
After-tax IPP Equity Internal Rate of Return (IRR) Hurdle Rate	12.0%	This is the assumed return on equity (over the life of the project) expected by investors, though projects risks may result in higher or lower IRRs. This IRR is calculated from the after-tax cash flow.
IPP Equity/Debt Fraction	60/40 (approximate)	The financial model maximizes the debt percentage, based on debt services constraints. Operating collateral requirements may reduce the amount of debt the project can take on.
Income Tax Rate	40.46%	Composite tax rate based on an assumed 35% federal and 8.84% state tax rate.
Annual Inflation Rate	2.50%	
Nominal Discount Rate	8.5%	Discount rate used for levelizing power prices

Table 5-2. Financial Assumptions		
Financial Assumptions	**Value**	**Basis**
		and net present value calculations. This is a typical utility WACC/discount rate.
Production Tax Credit ($/MWh)	$19.00	This is the 2006 value of the full PTC that is applicable to the wind and geothermal projects. The PTC is inflated each year.
PTC Term (years)	10	Wind and Geothermal projects are eligible for the Production Tax Credit in the first 10 years of operation.
Letter of Credit Cost	2.0%	The cost of obtaining a letter of credit for security; 1% and 3% were also modeled.
Source: Black & Veatch, Credit Requirements Modeling memorandum, September 2006.		

As in the original report, a letter of credit was assumed to be the standard instrument used for collateral. The cost of the letter of credit was assumed to be two percent of the face value of the collateral, which was the same cost used in the original report. The amount developers may pay for securing a letter of credit may vary; therefore values of 1.0 and 3.0 percent were also used as sensitivity cases. This cost was assumed to be an annual amount – for example, to maintain a $1,000,000 letter of credit would cost the developer $20,000 per year. Note that developers with strong balance sheets and investment grade credit may have costs lower than 1.0 percent.

Table 5-3 lists the two scenarios that were modeled: the credit requirements from the 2006 PG&E and SCE renewable RFOs, and the 2006 SDG&E renewable RFO. The development security and bid deposit were modeled as annual payments during the period between placing the bid and commercial operation date (see **Table 5-1**); assumed to be three years for wind and five years for geothermal. These annual payments were equal to the letter of credit cost (for example, 2 percent) multiplied by the capacity of the project and the deposit amount. For example, the 100 MW wind project would have a $40,000 annual carrying cost for the $2,000,000 letter of credit required for PG&E and SCE's $20 per kW development security.

For operating collateral, the letter of credit carrying cost was simply modeled as an expense to the project, similar to operations and maintenance or other expenses.

Table 5-3. Security Amounts		
	PG&E, SCE 2006 Renewable RFO	**SDG&E 2006 Renewable RFO**
Bid Deposit	$3/kW at short-list	None
Development Security	$20/kW	$10/MWh
Operating Collateral	12 Months Revenue	$30/MWh
Source: "The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement," CEC-300-2006-014, California Energy Commission, June 2006.		

Debt Reduction

The carrying cost of the letter of credit is the most obvious cost of credit to a project. Another possible "cost" is the reduction in the amount of debt the project can support due to the letter of credit necessary for operational collateral. The carrying cost of the letter of credit reduces the annual cash flow available for financing, therefore reducing the debt the project can take on due to the constraint of the debt service coverage ratio. The financial model used in the modeling attempts to maximize the leverage (debt) for each project, so additional collateral will reduce the amount of debt projects are able to take on.

Results of Quantifying Credit Requirements

The results for the renewable projects are shown in **Table 5-5** and **Table 5-6**. The results are compared to the cost of energy from a project without credit and collateral requirements (the amount in italics). The other entries are assuming the developer would need to raise the price of power to hold their returns at the same level to cover the costs of credit and collateral. The results are given in nominal levelized prices and the net present value over the 20-year life of the contract. This NPV is from the utility's perspective, as it represents the NPV of the payment streams over the life of the contract. The tables also show the difference in power prices and NPV for the different carrying costs of a letter of credit.

The renewable projects show modest per-MWh price increases for credit and collateral, ranging from $0.35 to $1.98 per MWh. While these may appear small, on an NPV basis the difference ranges from roughly $1 million to $5.5 million. Compared to the NPV of the total annual payments with no collateral, the cost increase due to credit and collateral ranges from half a percent to 3.5 percent. For PG&E and SCE, the cost increase due to credit and collateral is roughly equal to the cost of the letter of credit, while it is slightly lower for SDG&E.

PG&E and SCE's credit and collateral requirements appear to have an overall 66 percent greater cost increase than SDG&E's approach for the proxy projects. While this may seem large, the difference in levelized cost between PG&E/SCE and SDG&E is less than half a percent. SDG&E's approach to operating collateral is a fixed per MWh amount, as opposed to PG&E's and SCE's revenue-based approach. The fixed amount results in slightly lower cost increases, as the amount of required collateral does not increase as the cost of energy increases.

Table 5-5. Modeling Results for Wind Project					
	Levelized Cost of Energy ($/MWh)	**LCOE Increase ($/MWh)**	**NPV ($000)**	**NPV Increase ($000)**	**NPV Percent Increase**
No Collateral	*$53.97*		*$156,697*		
PG&E, SCE					
1% Cost of LOC	$54.54	$0.57	$158,357	$1,660	1.1%
2% Cost of LOC	$55.12	$1.15	$160,051	$3,354	2.1%
3% Cost of LOC	$55.72	$1.75	$161,779	$5,082	3.2%
SDG&E					
1% Cost of LOC	$54.32	$0.35	$157,706	$1,009	0.6%
2% Cost of LOC	$54.66	$0.69	$158,715	$2,018	1.3%
3% Cost of LOC	$55.01	$1.04	$159,724	$3,027	1.9%
Source: Black & Veatch, Credit Requirements Modeling memorandum, September 2006.					

The results for geothermal are very similar to the wind results due to two factors:

- SDG&E's collateral is based on per-MWh amounts, and the two projects have similar annual generation profiles.
- PG&E and SCE use a per-kW development security amount, which means the wind project requires higher development security. This difference is offset, however, because geothermal has a longer development/construction timeline.

Table 5-6. Modeling Results for Geothermal Project					
	Levelized Cost of Energy ($/MWh)	**LCOE Increase ($/MWh)**	**NPV ($000)**	**NPV Increase ($000)**	**NPV Percent Increase**
No Collateral	*$62.99*		*$177,669*		
PG&E, SCE					
1% Cost of LOC	$63.64	$0.65	$179,493	$1,823	1.2%
2% Cost of LOC	$64.30	$1.31	$181,353	$3,683	2.4%
3% Cost of LOC	$64.97	$1.98	$183,251	$5,581	3.6%
SDG&E					
1% Cost of LOC	$63.36	$0.37	$178,705	$1,035	0.7%
2% Cost of LOC	$63.73	$0.74	$179,740	$2,071	1.3%
3% Cost of LOC	$64.09	$1.10	$180,776	$3,106	2.0%
Source: Black & Veatch, Credit Requirements Modeling memorandum, September 2006.					

Conclusions Quantifying Credit Requirements

The cumulative cost of credit requirements for renewable projects appears to be roughly 2 percent to the cost of the project on an NPV basis. While this increase in cost may appear to be significant, it must be balanced against the potential negative financial impacts of contract failure or nonperformance.

The credit requirements of PG&E/SCE appear to incur greater costs than the requirements of SDG&E; however, the differences do not appear significant.

Chapter 6: Summary of Findings

Summary of Consensus Findings

This workshop aimed to identify strategies for reducing the effective cost of capital for renewable energy projects in California, mainly by focusing on the risks associated with power procurement. Discussions tended to coalesce around any one of four major risk mitigation functions–on behalf of the developer, the IOU, or the state:

1. Pooling risk to allow a diverse portfolio to provide greater protection.
2. Shifting risk to insurance or securitization intermediaries.
3. Shifting risk by allowing the purchasing utilities to take over the project with "step-in rights."
4. Forgiving failure by allowing utilities to recover the costs of purchasing replacement power at ratepayer expense, or waiving non-compliance penalties if the RPS targets are not met.

1. Pooling Risk via Portfolio

Using a clearinghouse market for power procurement and potential development of "capacity markets" in California may allow a more efficient use of capital by allowing intermediaries to back risks of nonperformance. As a developer of large projects, **FPL** noted that for renewable resources, the utilities and power purchasers can function effectively as a clearinghouse by developing a pool of suppliers and a portfolio of contracts that helps to pool risks.[90]

Milbank requested that the Energy Commission conduct additional work on pooling the risk of contract failure statewide.[91]

U.S. Renewables Group encouraged self-insurance via a statewide pool, instead of posting up to 12 months of revenues as operating security.[92]

2. Shifting Risk via Insurance or Securitization Intermediaries

Investor-owned utilities welcomed an expanded role for intermediaries who can better manage the financial risk or even some of the physical risk. IOU experience shows that bankruptcy of sellers is a legitimate wild card risk. Participants explored whether the utilities could self-insure to overcome the risk of default.

SCE expressed an interest in utility self-insurance, if the insurance premiums could be passed to the ratepayers (and credit requirements on individual power sellers could be reduced).[93]

SCE agreed that although none have come forward yet, third-party intermediaries could be available to mitigate the risk. Presentations from **MMC Securities**, **Goldman Sachs**, and **NECC** confirmed that securitization of risk through credit derivatives expands default risk coverage, and intermediary investors are increasingly providing capital for this type of collateral.

MMC Securities encouraged the transfer of credit risk to entities that have access to capital at a lower cost than power producer companies.

Expanded use of credit derivatives would allow outside investors to provide default risk coverage.

3. Shifting Risk via Step-in Rights and Pre-Existing Backstops

Several participants discussed alternatives to mark-to-market accounting in establishing the upper boundaries of financial risk in the event of project failure.

Milbank emphasized the value of risk protection provided by construction lender backstop, major equipment warranties, subordinated security interests, or other routine forms of insurance that are fundamental elements of any construction finance package. The contract can require that any insurance payouts caused by a *force majeur* be re-invested in the plant until it is operational again. Additionally, an EPC contractor's warranty for construction can be awarded to the power purchaser. The percentage of damages attributable to the replacement power purchase price can be directed to the utility. Additionally, Millbank suggested granting the IOU a lien on the project, subordinated to the senior lenders, as an alternative security deposit.

FTI Consulting concurred, noting that lenders provide themselves with backstop and protection via step-in rights, to preserve asset value. This should be applicable to utilities' procurement contracts.

Energy Investors Fund recounted their experience exercising step-in rights during the PG&E bankruptcy. They effectively ran gas-fired plants until PG&E could resume operations, and noted that, while this is not familiar territory for most counterparties, it is possible.[94]

SDG&E noted they now include step-in rights in their PPAs.

4. Reducing Utility Exposure to Failure

Virtually all participants expressed some level of interest in the CPUC establishing guidelines for the IOUs' financial liability if renewable energy project failures cause them to be non-compliant against RPS deadlines.

Additionally, participants noted the benefits of valuing the risk protection provided by CPUC oversight and involvement during the power procurement process, including the risk mitigation value of the least-cost, best-fit methodology.

A CPUC commitment to allow recovery of procurement losses within the ratemaking process was also mentioned.

Other Workshop Findings

Participants including Black & Veatch and PG&E expressed interest in changing credit requirements that inadvertently penalize projects with low capacity factors (such as wind and solar). This can be accomplished by **avoiding use of "nameplate capacity"** when determining the level of collateral or security.

Starwood and RCM Digesters believe that preconstruction costs, including credit requirements, are excluding small developers and narrowing the diversity of sellers. The developers with winning bids are only those with traditional balance sheets. However, SCE notes that there are no constraints on small developers teaming with those who have access to capital. Some large and ambitious projects are coming from small developers.[95] Developers believe that projects without major financing and **smaller projects (less than 1 MW) should be treated more equitably in the procurement process to stimulate small-scale generation by diverse entities in a manner consistent with the loading order**.

Small developers would benefit from **security deposits scaled as a square of the size of the project**, to reflect the scale of market exposure created by such small projects. Minimal security deposit requirements also facilitate participation of projects under 1 MW that are at the top of loading order—projects that currently have the greatest difficulty entering the market.

Millbank recommended that **security deposits be aligned with developer milestones**, such as the acquisition of construction financing, rather than the current requirement to put up half the development security deposit on contract execution, and half 30 days following CPUC approval.

Chapter 7: Recommendations

The goals of the State of California include:

- Increasing the amount of power plant capacity in California derived from renewable [and distributed] energy sources,
- Providing a market environment conducive to the lowest-cost financial structures being used for their development, and
- Enabling competition within a regulated environment.[96]

Several options may be considered to make progress towards these goals. Three recommendations outlined below address structural market issues, designed to provide the State of California with transformational policy options. Four additional recommendations cover incremental changes that do not appreciably change the existing market structure, as discussed during the workshop.

Market Transformation

1. Create a statewide insurance pool or other alternative risk transfer mechanism to cost-effectively manage power generation project credit risk exposures.[97]

A private administration compared to direct state-run management is also a possibility depending on the additional administrative costs required for the state to support the risk management activity. A pool structure is used for discussion purposes in this recommendation although other structures are also possible.

<u>Pool Operation</u>

All power development projects would be required to participate to mitigate adverse risk selection. Each member is charged an exposure-based premium intended to cover losses plus operating costs over a specific period of time, for example, three years. Claims are administrated and paid by the pool administrator to members in a similar fashion to standard insurance companies. One of the main differences between pool operation and stock insurance companies is in the premium charges. With a stock insurance company, premiums are fixed for the policy period, and there is no possibility of a refund if losses and expenses are less than anticipated. The excess revenues are profits. With an insurance pool structure, premiums can go up during the policy period. An additional “assessment” can be charged to the members if losses and expenses exceed targets. However, at the end of the period, if losses and expenses are less than the funds collected, the members get a refund or “dividend.”

There is also a secondary revenue stream from the investment income generated by the premium allocations. This revenue source will help offset losses and expenses, but the details of how this process functions is part of the pool structure implementation.

Project Pool Risk Management

The State of California would provide the capital base to pay claims on project credit defaults and performance guarantee shortfalls for policyholders in accordance with specific policy terms and conditions. The insurance policies could be single or multi-year in length, depending on the needs of the members. Policy wording and pool member requirements could limit claim payouts, especially for multi-year policies to protect the capital base for the other pool members. Premium charges will include a project developer's and project's historical claim performance to ensure members who receive claim payouts and thereby receive direct financial benefit from the pool pay higher premium amounts than similar projects with no claims.

Pool Feasibility Study

The objective of this work is to identify and quantify all costs and benefits to power generation participants and to California ratepayers. This study will investigate the legal issues including policy wording, the working details of administration, capacity requirements, and several other factors. The following list highlights some of the work that needs to be done:

- *Type of Insurance Model*: Given the conditions facing power generation project development in the State of California, another insurance model may be a better fit. The report needs to determine the best risk management model, and then investigate how the pool legal structure could be developed.
- *Pool Members*: The qualifications for pool participation and the anticipated current and future number of participants and their associated exposures need to be estimated. This information is needed to determine capacity requirements.
- *Policy Wording and Underwriting Guidelines:* Specific pool underwriting rules and proprietary policy language needs to be written and approved by pool members. The underwriting criteria need to be identified and the specific events or performance results that trigger claims need to be determined. With this information obtained, loss experience and data both in the frequency and severity can be compiled and used for modeling premium fees.
- *Compliance Inspections and Loss Control:* An engineering organization would be used to perform routine policy compliance inspections to ensure that policy terms and conditions are being enforced. While this organization is clearly an expense, the organization is a critical, integral part of the pool's success by providing guidance and, in some cases, strict direction to policyholders to identify and mitigate future claim events. Also, once a claim has occurred, the organization provides the engineering and technical skills required to adjust and administrate its fair resolution.
- *Capital Base, Premium Costs, and Risk:* A fundamental service of the pool is to provide an insurance facility that underwrites and manages the project risk of the pool members. If the pool member selection criteria are developed correctly, the effective loss experience should be extremely low. This projected loss experience, in essence, determines the capital that needs to be developed and also helps set the premium charges.

- *Reinsurance:* Generally insurance pools operate with funded capital to manage routine claims activity. Reinsurance acquisition for aggregate losses at sufficiently high attachments can be a cost-effective way of providing financial results stability that can minimize premium volatility.

The State of California's leadership either as the pool developer or pool administrator ensures that all "profits" are returned to the participants and the California ratepayers.

2. Allow California IOUs to benefit from leveraged equity investments in the same manner as private investment funds.[98]

<u>Background</u>

Several parties noted that capital has a natural tendency to seek the most efficient manner of deployment possible. This recommendation addresses the underlying conflict between regulated and unregulated financial mechanisms in the energy sector.

One of the traditional issues in the debate between IPP and IOU development and ownership of projects is the allocation of the benefits of leverage in the capital structure. This involves several elements: access to and use of non-recourse financing, accounting treatment of the related debt (off-balance sheet and off-credit), and treatment of and book income implications of the earnings from separate projects. Publicly held companies are more sensitive than their non-public counterparts (for example, the investment funds) to book implications.

Regulated IOUs are provided a return on rate-based assets; as publicly traded companies accountable to shareholders, they seek to maximize the earnings generated by the equity portion of the cost of that rate base. Increased earnings expand market value.

For a non-public, non-regulated investor in the energy sector, the goal is to maximize the return on equity. A fund manager's compensation is based on funds under management; their incentive is therefore to generate a good return, raise more funds, increase fee-based revenues, and continue the investment cycle by "leveraging up" their projects (borrowing against equity to return to original investors, create a new revenue stream for future equity investments, and borrow against the new stream, and so forth), either at the project level or at some level above that, including the fund level.

Unregulated subsidiaries of regulated utilities are a hybrid of these two approaches. They seek to generate book income for their holding company parent, so leveraging up the equity return is not the primary goal. They get more funding from the parent if they meet or exceed the corporate hurdle rate for unregulated investments, but primarily they are responsible for making a material contribution to the per-share earnings of the parent.

Research Requirements

The policy challenge is therefore to enable a structure that allows publicly-held IOUs to use additional leverage–either to encourage further investment or to lower the cost to ratepayers (directly or though adding more competition to the market). A key element of this recommendation includes the allowance of partial ownership (and therefore some control) by IOUs with CPUC oversight. Returns from such an entity would be shared equally between the utilities' shareholders and ratepayers—providing both the market and regulated entities with a financial incentive to develop new capacity.

Research is required to identify the most facilitative ownership structure in this context. This report recommends the Energy Commission and CPUC investigate the state and federal implications of such a capital structure, including SEC oversight. One approach might include the development of comparative analyses to explore the viability of various ownership structures, and constraints involved: accounting, tax, financial structure, regulation, etc.

For capital-intensive renewable projects, underusing leverage means they are denied the potential benefits of the cheapest form of capital: tax-deductible, long-term, fixed-rate debt. This is far more financially attractive than equity, with its higher return requirements. To this end, private investment funds maximize their use of non-recourse (or limited recourse) debt at every possible level, from the project itself on up. Despite recent interest rate increases, tax-deductible debt is still the cheapest form of capital in our markets.

3. Modify market structure to expand use of clearinghouses. A limited segment of the current CPUC long-term procurement effort aims to expand cost sharing of certain new projects by requiring the energy component to be auctioned to a high bidder, which may or may not be the IOU.[99] These periodic auctions could be expanded to include other generators aside from those involved with the current "limited and transitional" procurement effort. Additionally, the separate IOU auctions could be merged to create a larger pool of potential energy suppliers. Clearing could be used to pool the separate auction transactions.

Separate periodic auctions in RPS procurement could also be consolidated. Renewable resource procurement occurs (virtually) annually with individual RFOs being issued by each IOU. These RFOs could occur on simultaneous tracks and be harmonized to allow simultaneous participation of potential generators interested in offering power to any IOU. This could pool the demand of the IOUs, and the RPS demand of other LSEs, which could give generators multiple potential buyers. A market structure that allows RFO respondents to secure contracts with multiple LSEs could encourage competition among LSEs for strong generation projects, and allow generators to secure contracts from multiple LSEs, which would expand the ability of sellers to diversify with multiple PPAs and possibly improve credit ratings.

Incremental Changes to Existing Market Structure

1. Differentiate Risk by Project Size and Technology. Distributed energy systems offer a variety of locational and security benefits that increase in proportion to their share of the total load served; however, each project has very little individual impact on the IOUs' load-serving requirements, or their RPS obligations. The CPUC can relieve this conflict between regulatory priorities and (inadvertent) financial overkill by reviewing the need to post collateral for all renewable energy projects under 1 MW.

Additionally, IOUs should be encouraged to avoid the use of nameplate capacity, avoid the use of "mark-to-market" accounting, and develop a sliding scale that requires exponentially greater collateral posting for large projects when setting credit requirements. These steps should reduce the credit demands on small developers, developers of distributed generation, and developers of low capacity factor technologies (that is, intermittent renewable energy systems) at the top of the loading order.

2. Establish the value of CPUC oversight during the IOU procurement process. The CPUC and IOUs should work together to determine the value of risk protection provided by CPUC involvement that occurs during the power procurement process, including the risk mitigation value of the least-cost, best-fit methodology and any CPUC commitment to allow recovery of procurement losses with ratemaking or to set RPS non-compliance penalties with discretion. The CPUC should also consider standardization of IOU credit requirements to provide a level playing field for power sellers bidding on multiple RFOs.

3. Encourage securitization and self-insurance of power purchasers. The CPUC should determine whether legitimate, physical risk coverage can be provided through securitized credit derivatives and investigate the viability of allowing the cost of insurance paid by IOUs against default or non-performance of power sellers to be recoverable from ratepayers.

4. Accelerate long-term contracting. The *2005 IEPR* found that more long-term power contracts would facilitate investment in power plants.[100] Participants in the June 2006 workshop indicated that a high level of project financing is available. Consistent with the recommendations of the *2005 IEPR*, the CPUC should expand its efforts leading IOUs to procure energy and capacity through long-term contracts.

Endnotes

[1] *Building a "Margin of Safety" into Renewable Energy Procurements: A Review of Experience with Contract Failure*, prepared by: KEMA, Inc. for the Energy Commission, January 2006. CEC-300-2006-004.
[2] This varies considerably among utilities, across situations, and by power technology (p.42, KEMA, January 2006).
[3] PG&E presentation at June 27, 2006 workshop transcript p. 39.
[4] Caithness noted the vast majority of developers continued to serve the California market during the crisis of 2001, whether they were paid in a timely manner or not. Workshop transcript p. 83.
[5] *The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement*, Prepared by: KEMA, Inc. for the Energy Commission, July 2006. CEC-300-2006-014. Mark-to-market accounting for collateral seeks to protect the utility from exposure, if the wholesale market price is above the contract price. Market prices above the contract price mean that if the project underperforms or is in default, the utility will have to purchase more expensive power on the market. Mark-to-market accounting attempts to quantify this exposure by aggregating the total amount future wholesale prices could be above the contract price. For example, if prices have a 95 percent chance of being $5/MWh above the contract price, then the utility's total exposure is $5/MWh times the annual generation times the number of years remaining on the contract. For a 20-year contract, this amount can reach large figures very quickly, so utilities normally only ask for some percentage of the total exposure to be covered with collateral. For short term (5-year) marketing contracts, utilities are more likely to ask for full collateral. Calculating the amount of collateral required for mark-to-market accounting requires knowledge of future market price predictions, as well as sophisticated financial analysis tools. Most power marketers have the capability and tools to calculate mark-to-market collateral amounts, which is important as the amount of collateral required is recalculated on an annual, weekly, or even daily basis depending on the contract. Mark-to-market accounting poses certain difficulties for renewable developers. Renewable developers generally do not have the expertise or tools to calculate the collateral amounts necessary. Periodic recalculation means the developer cannot know how much collateral will be required over the life of the contract up front. This makes it difficult to price the credit required into the price of power when bidding. In addition, there is no liquid or wholesale market in California for renewable energy, so it is unclear what price the utility should use when making mark-to-market calculations for renewable energy purchases.
[6] SCE presentation at June 27, 2006, workshop.
[7] Workshop transcript, p. 84.
[8] Black & Veatch presentation at June 27, 2006, workshop.
[9] *The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement*, Prepared by: KEMA, Inc. for the Energy Commission, July 2006. CEC-300-2006-014.
[10] SCE's pre-2006 mark-to-market requirements have been removed from recent RFOs (p.26, KEMA, July 2006).
[11] *2005 Integrated Energy Policy Report*, November 2005. CEC-100-2005-007CMF.
[12] *2006 Renewable Energy Investment Plan*, February 2006. CEC-300-2006-003-CMF (http://www.energy.ca.gov/renewables/).
[13] *Building a "Margin of Safety" into Renewable Energy Procurements: A Review of Experience with Contract Failure*, prepared by: KEMA, Inc. for the Energy Commission, January 2006. CEC-300-2006-004.
[14] *The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement*, Prepared by: KEMA, Inc. for the Energy Commission, July 2006. CEC-300-2006-014.
[15] *2005 Energy Action Plan II* (http://www.energy.ca.gov/energy_action_plan/index.html). The loading order identifies energy efficiency and demand response as the state's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, the loading order specifies renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, the loading order supports clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter.
[16] CPUC 2006 Work Plan (January 17, 2006).

[17] CPUC Decision July 20, 2006 (D.06-07-029; R.06-02-013).
[18] California ISO, Credit Policy & Procedures Guide, June 2006 (p.6).
[19] California ISO presentation at June 27, 2006, workshop.
[20] Starwood comments at June 27, 2006, workshop.
[21] California ISO presentation at June 27, 2006, workshop transcript, p. 122.
[22] Milbank presentation at June 27, 2006, workshop.
[23] Mark-to-market accounting expands the risk protection and collateral requirement if the market price of energy is above the contract delivery price, and reduces the collateral if market prices are near or below contract prices (p. 6, KEMA, July 2006).
[24] Black & Veatch presentation at June 27, 2006, workshop.
[25] Black & Veatch presentation at June 27, 2006, workshop.
[26] PG&E written comments on workshop filed July 11, 2006.
[27] Black & Veatch presentation at June 27, 2006, workshop transcript, p. 23.
[28] Black & Veatch presentation at June 27, 2006, workshop.
[29] Starwood comments at June 27, 2006, workshop.
[30] Starwood presentation at June 27, 2006, workshop.
[31] Caithness comments at June 27, 2006, workshop transcript, p. 139.
[32] SCE written comments on workshop filed July 11, 2006.
[33] Starwood comments at June 27, 2006, workshop transcript, p. 129.
[34] FPL comments at June 27, 2006, workshop transcript, p. 135.
[35] Caithness comments at June 27, 2006, workshop.
[36] Starwood presentation at June 27, 2006, workshop.
[37] Starwood presentation at June 27, 2006, workshop.
[38] CPUC Decision May 25, 2006 (D.06-05-039; R.04-04-026).
[39] *2005 Integrated Energy Policy Report*, November 2005. CEC-100-2005-007CMF.
[40] PG&E presentation at June 27, 2006, workshop.
[41] PG&E presentation at June 27, 2006, workshop.
[42] SCE presentation at June 27, 2006, workshop.
[43] SCE comments at June 27, 2006, workshop transcript, p. 67.
[44] SDG&E presentation at June 27, 2006, workshop.
[45] SDG&E presentation at June 27, 2006, workshop.
[46] SCE presentation at June 27, 2006, workshop.
[47] Black & Veatch presentation at June 27, 2006, workshop.
[48] Milbank presentation at June 27, 2006, workshop.
[49] CPUC Decision May 25, 2006 (D.06-05-039, p.38; R.04-04-026). This CPUC decision declined establishing a maximum allowable Bid Deposit requirement of $3 per kW, noting that the requirements of PG&E, which requires no deposit at the time of bidding and a bid deposit of $3/kW once a project is short-listed, seem reasonable for use by other IOUs.
[50] Milbank presentation at June 27, 2006, workshop.
[51] SCE written comments on workshop filed July 11, 2006.
[52] CPUC Decision May 25, 2006 (D.06-05-039, pp.34 to 38; R.04-04-026).
[53] Milbank presentation at June 27, 2006, workshop.
[54] Milbank comments at June 27, 2006, workshop.
[55] Milbank presentation at June 27, 2006, workshop.
[56] EIF presentation at June 27, 2006, workshop.
[57] EIF presentation at June 27, 2006, workshop.
[58] Milbank presentation at June 27, 2006, workshop.
[59] SCE written comments on workshop filed July 11, 2006.
[60] MMC Securities presentation at June 27, 2006, workshop.
[61] MMC Securities presentation at June 27, 2006, workshop.
[62] MMC Securities presentation at June 27, 2006, workshop.
[63] CalPERS presentation at June 27, 2006, workshop.
[64] MMC Securities presentation at June 27, 2006, workshop.
[65] SCE written comments on workshop filed July 11, 2006.
[66] SCE written comments on workshop filed July 11, 2006.
[67] CalPERS presentation at June 27, 2006, workshop.

[68] EIF presentation at June 27, 2006, workshop.
[69] EIF presentation at June 27, 2006, workshop.
[70] Goldman Sachs presentation at June 27, 2006, workshop.
[71] CPUC Decision July 20, 2006 (D.06-07-029; R.06-02-013).
[72] Goldman Sachs presentation at June 27, 2006, workshop.
[73] NECC presentation at June 27, 2006, workshop.
[74] SCE written comments on workshop filed July 11, 2006.
[75] NECC comments at June 27, 2006, workshop.
[76] RCM Digesters written comments on workshop filed July 11, 2006.
[77] FPL comments at June 27, 2006, workshop.
[78] Goldman Sachs comments at June 27, 2006, workshop.
[79] SCE written comments on workshop filed July 11, 2006.
[80] PG&E written comments on workshop filed July 11, 2006.
[81] PG&E written comments on workshop filed July 11, 2006.
[82] PG&E written comments on workshop filed July 11, 2006.
[83] RCM Digesters Inc. is the entity succeeding RCM Biothane, LLC.
[84] RCM Digesters written comments on workshop filed July 11, 2006.
[85] RCM Digesters written comments on workshop filed July 11, 2006.
[86] RCM Digesters written comments on workshop filed July 11, 2006.
[87] RCM Digesters written comments on workshop filed July 11, 2006.
[88] *The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement*, CEC-300-2006-014 California Energy Commission Contractor's Report, June 2006. http://www.energy.ca.gov/2006publications/CEC-300-2006-014/CEC-300-2006-014.PDF
[89] Capacity payments are not modeled.
[90] FPL comments at June 27, 2006, workshop.
[91] Milbank presentation at June 27, 2006, workshop.
[92] Workshop transcript, p. 126.
[93] Workshop transcript, p. 86.
[94] Workshop transcript, p. 181.
[95] US Renewables comments at June 27, 2006, workshop.
[96] California has a long legislative and administrative history in support of these three goals, which are also called out in the Energy Commission's *2003 Integrated Energy Policy Report.*
[97] This concept was developed over several years between Rick Jones, currently with Hartford Steam Boiler/AIG, Anne-Marie Borbely-Bartis, Sentech Corp., and Merwin Brown, Energy Commission Program Manager for Transmission R&D.
[98] Developed in consultation with Philip Huyck.
[99] CPUC Decision July 20, 2006 (D.06-07-029; R.06-02-013).
[100] *2005 Integrated Energy Policy Report*, November 2005. CEC-100-2005-007CMF.